AUSTRALIAN JOURNAL OF ENGINEERING AND TECHNOLOGY RESEARCH (AJMFR)
Vol. 2, Issue 2 - 2017

MODEL BASED APPROACH TO REVIVE THE LOADED-UP WELLS THROUGH MICRO-TUBING SOAP INJECTION IN SINDH REGION

Amir Mawia Siddiqui
Institute of Petroleum & Natural Gas Engineering, Mehran University of Engineering & Technology, Jamshoro, Pakistan

Ubedullah Ansari
Institute of Petroleum & Natural Gas Engineering, Mehran University of Engineering & Technology, Jamshoro, Pakistan

Temoor Muther
Department of Petroleum & Natural Gas Engineering, Mehran U.E.T., Shaheed Z.A Bhutto Campus, Khairpur Mirs, Pakistan

ABSTRACT

Liquid loading occurs in a gas well when the velocity of the producing gas decreases to a specific velocity (critical velocity) that is necessary for the connate water to be lifted with producing gas. Gas well requires much higher potential to lift the produced liquid (connate water) out from the well and if the well does not have ultimate potential than connate water starts to accumulate inside the well bore and also in completion string. Liquid column creates hydrostatic pressure and production stop automatically if this hydrostatic pressure is greater than reservoir pressure. In order to revive the production again from loaded-up well, it is necessary to unload the well. Different types of surfactants (anionic, amphoteric, cationic, and non-ionic surfactants) are available which are injected into the wellbore to unload the gas well.

All injected surfactants react with the loaded liquid to create the certain mechanism, as a result well starts to become de-liquefied. Mechanisms are;

- The decrease in surface tension of the loaded liquid.
- The decrease in loaded liquid density.
- Increase the effective surface area of the liquid

In this study, efforts have been made to develop a de-liquefaction well bore model for a gas well by using **PROSPER** software in order to de-liquefy the well by using micro tubing soap injection technology. It was

concluded that loaded volume was enclosed 98.84 % in the casing and 1.16 % in tubing which created a hydrostatic pressure of 1947 psi. In order to unload the well volume required to be injected into the well was 215.42 bbl with the surfactants concentration of 14000 ppm at the flow rate of 1500 Mscf/d.

Keywords: Hydrocarbons, Foamers, surfactant, Tubing, Gas Well, Prosper Software.

1. INTRODUCTION

The terminology of liquid loading in a gas well is actually the unavailability of the producing gas. Liquid loading is one of the important causes for the reduction or loss of production in the gas well. Usually, artificial lift techniques are used to remove the liquid from the gas well. [1]

Liquid loads in gas wells are classified into three categories: condensed liquid, external liquid, and formation liquid. [2]

Mostly in well bore, liquid loading occurs when the velocity of producing gas decreases to a velocity which is required to lift the liquid. The velocity at which the liquid has the tendency to fall instead of rising is called “critical velocity” of a well. [3]

The produced liquid would accumulate within the well bore causing a reduction in production and the time shortened, until the well no longer will produce. [4]

Following are different types of methods to unload the well bore,

- Reciprocating rod lift
- Small-ID tubing
- Gas lift
- Plunger lift
- Swabbing
- Flow controllers
- Submersible pump
- Jet pump
- Micro tubing soap injection. [5]

In the US about 90% of the producing gas wells are operating in liquid holdup regime. [6]

The interest of industry towards deliquification by using soap has become more dramatic. [7]

Soap injection is one of the economical and simplest methods that have been ever used successfully to unload the wellbore liquid in the present era around the world. [8]

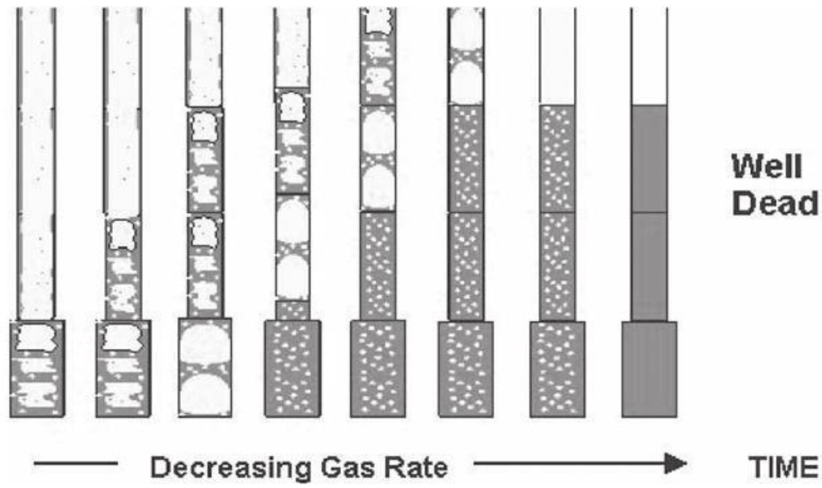


FIG. 1: LIFE HISTORY OF GAS WELL

2. PROBLEM STATEMENT

Starting from the first day of gas production, the reservoir pressure declines continuously and a time comes when the production of gas decreases to the critical velocity of the well, causing liquid loading in well bore. This liquid loading causes erratic sludge flow and decreases the production rate and if this liquid is not removed timely than more liquid would accumulate in well bore and causing no production. This liquid also corrodes the downhole completion equipment. Indeed, this issue needs to be resolved in order to avoid economical loss in terms of equipment and productivity.

3. FOAM INJECTION TECHNIQUE

Surfactants (foaming agents) have quite a lot of applications in oil and gas field operations. They may use the drilling fluid as a circulating medium for drilling a well, it may be used for well cleanout purpose, and it may also be used as a fracturing fluid for hydraulic fracturing. All the above mention applications are quite different from the application of foam for the removal of liquid (connate water) from the column of producing gas wells. In the former applications, foams are generated at the surface with prescribed mixing with surfactants and other additives and water is used as the main source for generating the foams. While on the other hand, gas well deliquification involves slightly different procedure from the above. The calculated amount of Surfactant is injected from the surface to the downhole at the optimum pressure required for the surfactants to be injected, where it reacts with the connate water and generates foam.

The uniqueness of this method is that when foams are generated it creates bubble films which carry little amount of water and produces more effective surface area causing low-density mixture and less gas slippage. Foams are effective to transport the liquid from downhole to the surface at a low gas rate.

Foam is basically an emulsion formed with gas and liquid (connate water). A liquid film separates, gas bubbles from each other in the foam. Foaming agents (surfactants) are generally used to decrease the surface tension of the liquid so that more gas-liquid may disperse. The liquid film has two surfactant layers between bubbles back to back with liquid enclosed between them. The method of fixing the liquid and gas together can be quite effective to unload liquid from even low volume gas well. [13]

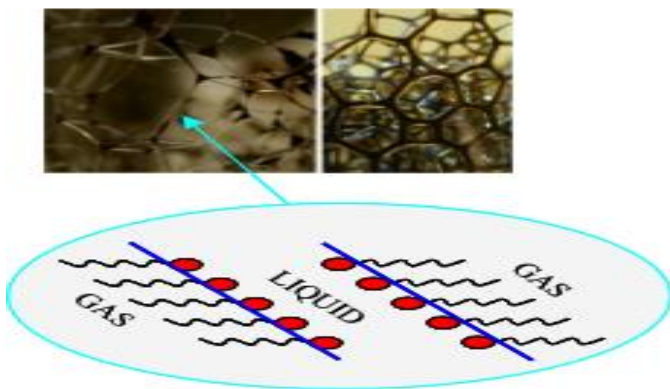


FIG. 2: SURFACTANT ARRANGEMENTS AT THE GAS LIQUID INTERFACE OF FOAM

4. MICRO TUBING LIFT TECHNOLOGY

Enhancing the liquid production by adding foaming agents (surfactants) to the well is becoming a more popular method. In the MTSI technique, a small diameter tubing (approximately 1/4") is being installed either inside or outside the production tubing in order to allow the foaming agents or surfactants to be injected from the surface to the certain depth to de-liquefy the gas wells. Deliquifying agents are usually injected from surface to the subsurface by using a standard chemical storage tank and a high-efficiency pump (fig 3).

An MTSI system gives a method to specifically transmit the lift technique to enhance the foam injection application in loaded gas well. In real meaning, the MTSI technology is actually a microtubing system which is mechanically hung on the well. [14]

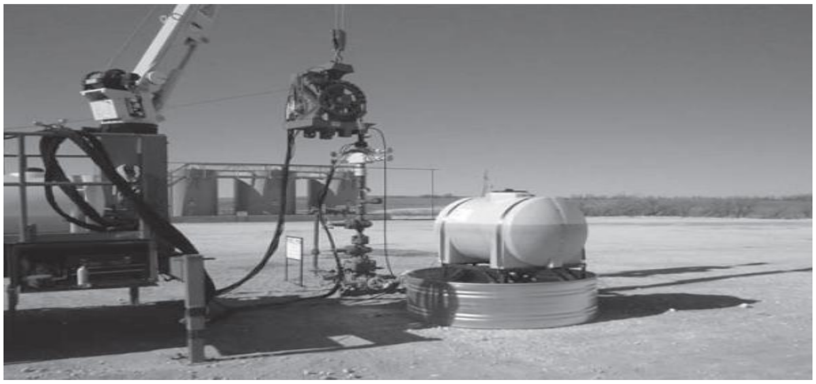
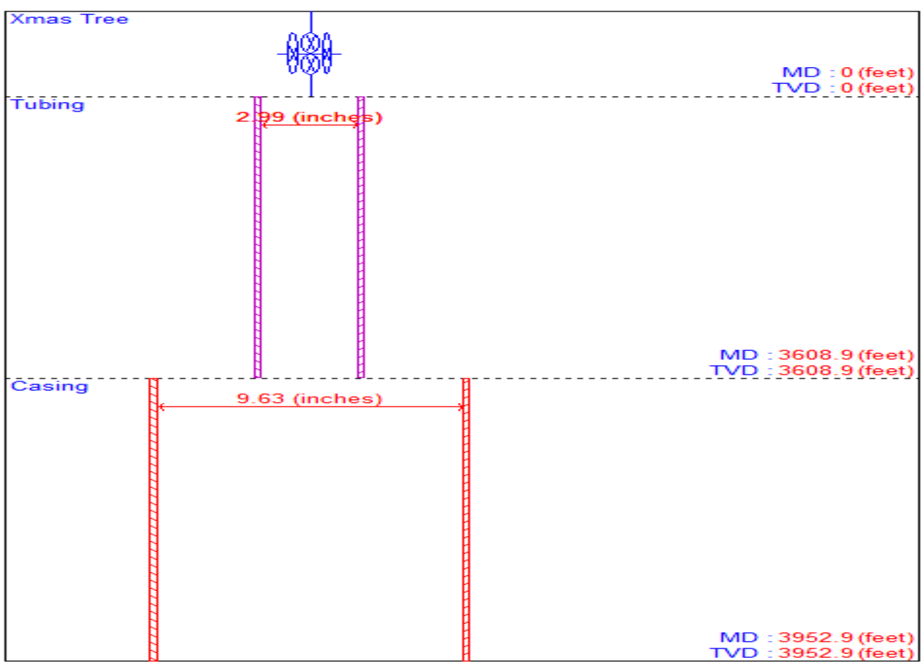


FIG. 3: MICRO COILED TUBING UNIT (MCTU)

5. CASE STUDY

The well X was drilled as development well and completed in early 1997 at a TVD of 4432ft in a sand B at a field ABC owned by a multi-national exploration and production company. In this project, we have taken the well completion data, DST data and geological data from the company.

The down-hole completion equipment is shown in the figure below:



C:\Users\AMIR MAWIA\Desktop\SIDDIQUI2.Out

FIG. 4: DOWN-HOLE COMPLETION SKETCH

Followings attached are the screenshots of step by step procedure in IPM prosper from data input to model generation. Below is the screenshot of system summary.

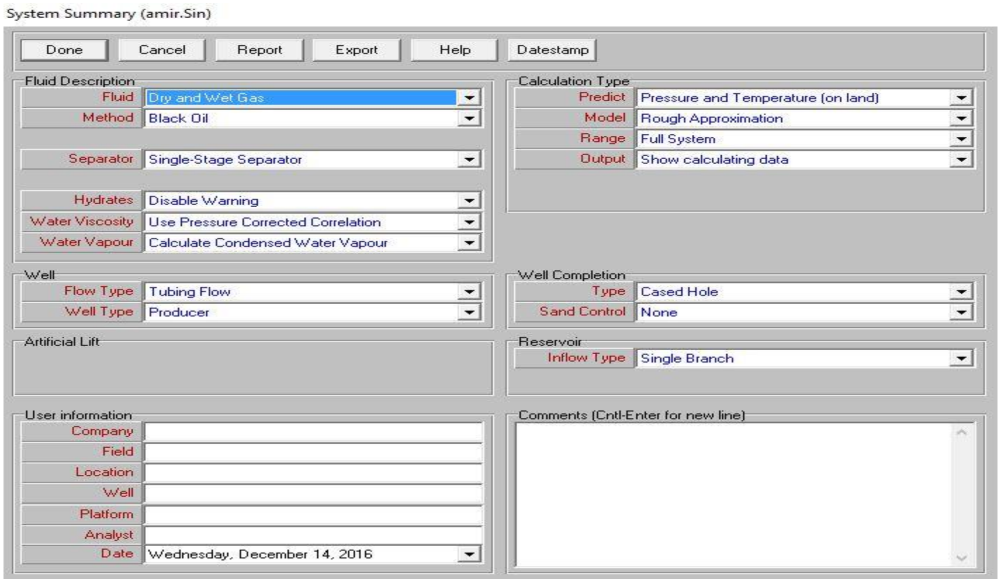


FIG. 5: PROSPER SCREENSHOT SHOWING THE -SYSTEM SUMMARY SCREEN

After defining the tubing configuration and associated PVT of the fluids flowing in the tubing, the IPR for the well is defined next, as shown in figure: 6 below,

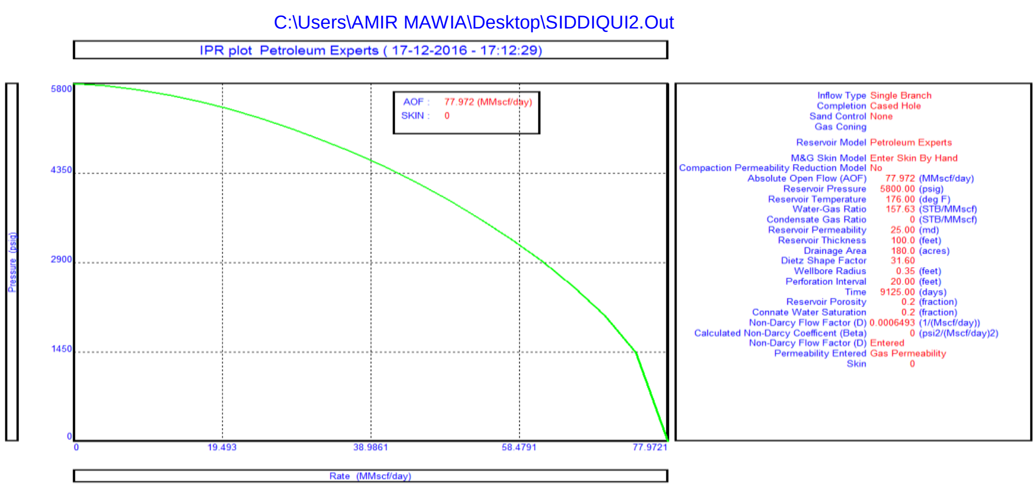


FIG. 6: IPR OF THE WELL

Darcy's Model has been applied to solve the IPR for this part of the reservoir. This IPR model requires permeability, thickness, skin and reservoir pressure. The values used for these parameters are listed in the above plot. This gives an IPR with AOFP and PI for the well.

After Defining the IPR, the next step is to define the VLP for the well as shown in the figure: 7 below,

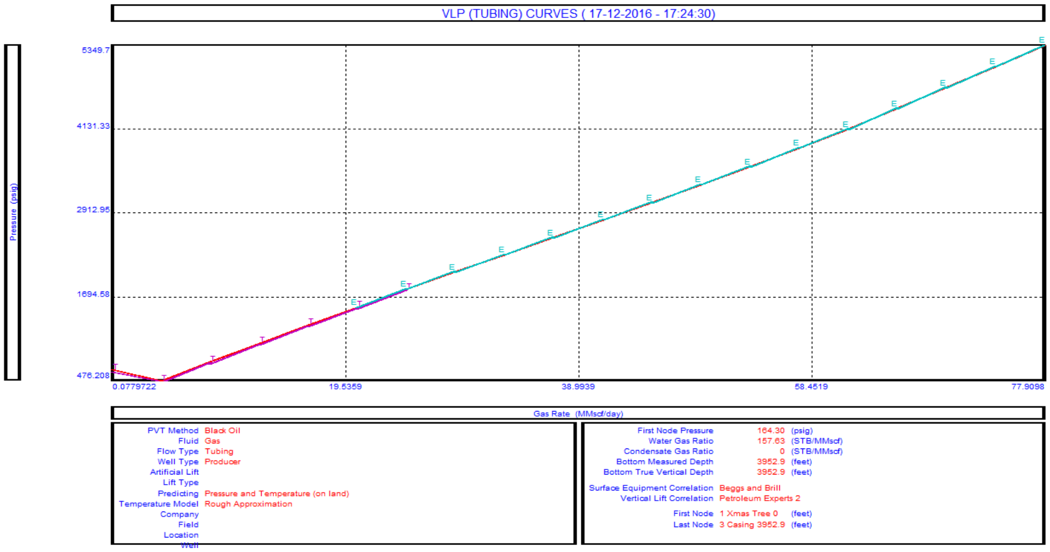


FIG. 7: VERTICAL LIFT PERFORMANCE OF THE WELL

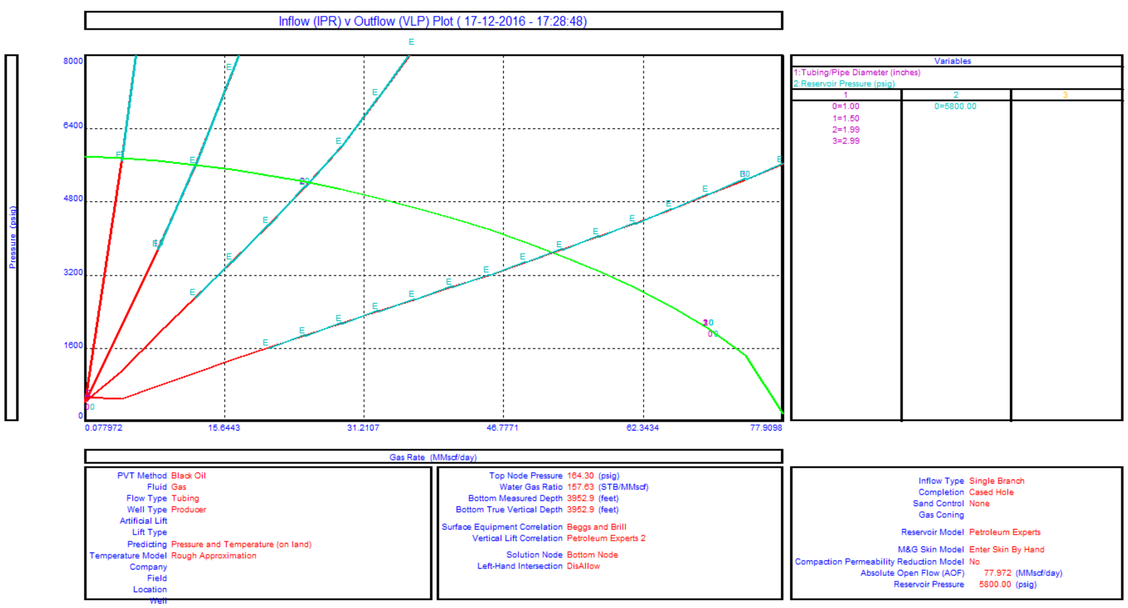


FIG. 8: INFLOW VS OUTFLOW CURVES (VLP)

The intersection of 2.992 tubing curve and IPR gives the natural flow of 51 MMSCF/D, and also shows the effect of different tubing sizes. As the figure shows, for the 1-inch tubing size, the erosional point comes at low rates, and it increases from 1, 1.5, 1.995 and 2.992. For 2.992 the tubing curve the greater portion is towards the left and lesser portion is towards the right of the intersection. So the 2.992 tubing size should be selected.

6. UNLOADING WELL-X USING MTSI TECHNOLOGY

The MTSI technology was performed on well X to unload it. The first step was to locate the static liquid level in the well bore. Gradient survey used to calculate the total amount of fluid present in the wellbore.

Step#01: Total Fluid Residence in the Well Bore

Taken the data from the tables and the gradient survey data, the fluid residence in the well bore can be calculated by using the following formula:

As we know that:

$V=0.178\,\pi\, r^2 h$ (bbl)

As we know, volume of cylinder = $\pi\, r^2\, h$

Here 0.178 is a conversion factor 1bbl = 5.615 cubic ft

As r=d/2

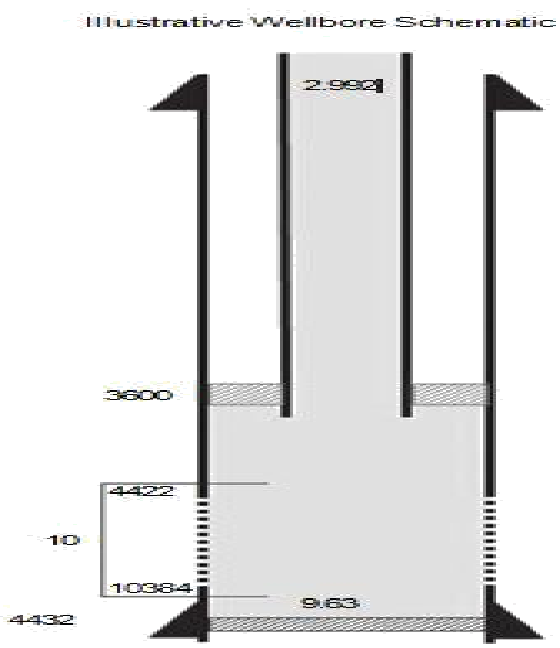


FIG. 9: FLUIDRESIDENCEINTHE WELL BORE

(a) Fluid residence in tubing D="2.992"

Depth of liquid level (from gradient survey) 3500 to 3600

Put the values in the formula,

$V=0.178 \times 3.14 \times (2.992/2)^2 \times 100$

V= 125.153 bbl

(b) Fluid residence in the Casing D= "9.625"

Depth of liquid level (from the gradient survey) above the perforation i.e.4422 to3600

Put the values in the formula,

$V=0.178 \times 3.14 \times (9.625/2)^2 \times 822$

V= 10646 bbl

Total fluid residence will be= Vtubing+ Vcasing

V_{Total}= 125.153 + 10646

V_{Total}= 10771 bbl

(c) % of liquid in tubing = (125.153*100)/10771

% of liquid in tubing =1.16%

(d) % of liquid incasing = (10646*100)/10771

% of liquid incasing = 98.84%

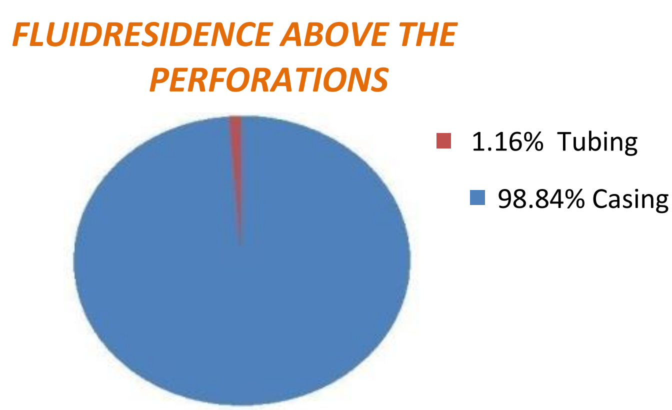


FIG. 10: PIECHART SHOWING THE PERCENTAGES OF LIQUID IN THE CASING AND TUBING.

Step#02: Concentration of liquid foaming agent

The following equation can be used in order to determine the optimum concentration of the liquid foaming agent in the surface storage tank:

$C_{sfa} = C_{min} (Q_{liq} + Q_{fa}) / Q_{fa}$

Where:

C_{sfa} = surface foaming agent concentration (concentration to be prepared),

C_{min} = minimum effective concentration, %

Q_{liq} = amount of produced liquids, m^3/day

Q_{fa} = foaming agent injection rate, m^3/day

To avoid hydrate forming problems, it is sometimes recommended to use methanol as a diluent. C_{min} is calculated in the laboratory and depends upon the salt concentration of the produced water and other impurities.

Step#03: Critical Rate and Velocity calculations.

The Critical velocity of gas to unload the well can be calculated by using the Turner's

Equation given below,

Equation given below, or

$$V_{gc} = \frac{K\, \sigma^{1/4}(\rho_1-\rho_g)^{1/4}}{P_g^{1/2}} \quad \text{.....................} (5.1)$$

Where

V_{gc} = critical gas velocity

k = constant(1.92 turner, 1.59 coleman)

σ = surface tension liquid to gas (dynes/cm)

ρ_1 = density of liquid (lb/ft^3)

ρ_g = density of gas (lb/ft^3)

Z = compressibility factor

$$Q_{gc} = \frac{3.06PAV_{gc}}{(T=460)Z} \quad \text{.................................} (5.2)$$

Using the graph as shown in figure 11,

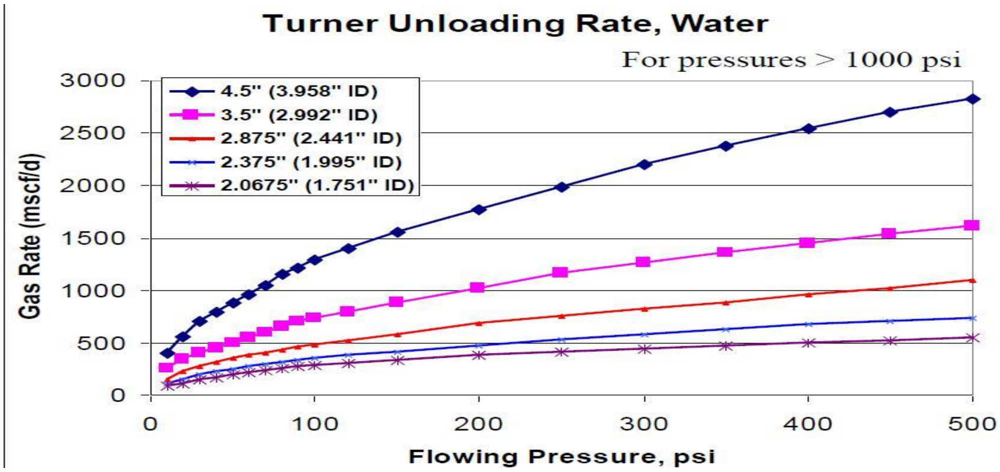


FIG. 11: TURNER'S UNLOADING RATE CHART.

For the bottom-hole pressure of 410.398 psi, the unloading rate is calculated from the above graph i.e. 1500 Mscf/d.

Step#04: Injection Volume Calculation

From the knowledge of the liquid volume in the well to achieve a maximum concentration of 14,000ppm was calculated as follows.

$V_{Inj} = V_L \times 2/100$

Where V_L is the volume of liquid in the well bore

$V_{Inj} = 10771 \times 2/100$

$\boxed{V_{Inj} = 215.42 \text{ bbl}}$

Step#05: Calculation of foot valve pressure

By using the following data, valve set pressure, pump injection pressure and actual bottom hole pressure is being calculated as:

Pump Operating Pressure = 500 psi

Chemical Wt = 8.4500 ppg

Flowing BHP = 410.398 psi

Depth to valve = 4432 ft

Hydrostatic pressure in micro-tubing may be calculated as,

$\mathbf{P}_{hyd}$= 0.052 × valve depth × weight of chemical

$\mathbf{P}_{hyd}$ = 0.052 × 4432 × 8.45 = **1947.42 (psi)**

After calculating the P_{hyd} now it is required to calculate valve set pressure which may be calculated as:

$\mathbf{P}_{valve}$ = pump operating pressure - flowing BHP + P_{hyd}

$\mathbf{P}_{\mathbf{valve}}$ = 500 - 410.398 + 1947.42 = **2037.0228 psi**

Step#06: Shut-inn Time

The minimum shut-inn time required prior to start-up of surfactant closed well (hours) was calculated as:

$T_{S/I} = d_{md}/1000 + 2$

$T_{S/I} = 4432/1000 + 2$

$T_{S/I}$ **= 6.432 hours**

7. CONCLUSION

The intersection of TPR (VLP) and IPR gives the natural flow and from the above model. It can be easily concluded that the intersection of 2.992 tubing curve and IPR gives the natural flow of 51MMSCF/D. It also shows the effect of different tubing sizes. As the model shows that for the 1-inch tubing size, the erosional point comes at low rates, and it increases from 1, 1.5, 1.995 and 2.992. For 2.992 the tubing curve the greater portion is towards the left and lesser portion is towards the right of the intersection. So, the 2.992 tubing size should be selected. As the total liquid loaded volume was found to be 10771 bbl which is loaded 1.16% into tubing and 98.84% into casing so, a concentration of 14000ppm and injection volume of 215.42 bbl of surfactants at the rate of 1500mscf/d is required to unload the well successfully and the minimum shut-inn time required prior to start-up of surfactant closed well (hours) was calculated and determined $T_{S/I}$= 6.432 hours.

ACKNOWLEDGMENT

This research work was carried out at the Institute of Petroleum & Natural gas Engineering, Mehran University of Engineering & Technology Jamshoro, Sindh, Pakistan. The project was supported by Prof. Dr. Suhail Ahmed Soomro, Engr. Ubedullah Ansari, Prof. Dr. Saleem Qadir Tunio, and Engr. Temoor Muther.

REFERENCES

[1] Zheng Liang, Fei Wang, Xiong Deng, "A novel technology of combining soap injection and compression to lift liquid in liquid flooded gas wells", Journal of Natural Gas Science and Engineering 19, 2014, pp 147-151.

[2] Peijun Zhang, Xubin Cheng, Ronghe Liu, Jihui Yang, Ke Zheng, "Abnormal liquid loading in gas wells of the Samandepe Gasfield in Turkmenistan and countermeasures", Natural Gas Industry B, Volume 2, Issue 4, October 2015, Pages 341-346.

[3] Lei Liu n, XiaobaiLi, LiTong, YanweiLiu, "Effect of surfactant additive on vertical two-phase flow", Journal of Petroleum Science and Engineering115, 2014, pp 1–10.

[4] Jiang, Y., Baoshan, G., Guanke, Y., Yongjun, L., Xiaoling, W, "Effect of Dynamic Surface Activity of Surfactant on Performance of Soap for Gas Well Deliquification", SPE 165366, SPE Western Regional and AAPG Pacific Section Meeting, Monterey, California, USA, April 2013, pp 1-5.

[5] Ozmen binli, "Overview of solutions to prevent liquid-loading problems in gas wells", The graduate school of natural and applied the science of Middle East technical university, 2009.

[6] Han-young park, "Decision matrix for liquid loading in gas wells for cost/benefit analysis of lifting options", Submitted to the Office of Graduate Studies of Texas A&M University, 2008.

[7] Liu, L., Scott, S.L, "Effect of flow improvement chemicals on vertical zero net- liquid flow", In: Gregory, G.A., Redus, C.(Eds.),Proceedingsofthe2ndNorth American Conference on Multiphase Technology, Professional Engineering Publishing Ltd.,England, 2000, pp 35–52.

[8] Shameem, S., Jiansui, Y,"Successful application of soap for lifting liquids from low-pressure gas wells", SPE 52122, SPE Mid-Continent Operations Symposium, Oklahoma City, Oklahoma, USA, March 1999, pp 1-11.

[9] Jiang Yang, Vladimir Jovancicevic, Sunder Ramachandran, "Soap for gas well deliquification", Volume 309, Issues 1–3, 1 November 2007, pp 177–181.

[10] James F. Lea, James Fletcher. Lea, Henry V. Nickens, "GAS WELL Deliquification(Second Edition) Chapter 8 – Use Of Soap To Deliquify Gas Wells", 2008, pp 193–240.

[11] Price, Brian et al, "foam assisted lift-importance of selection and application", SPE-106465-MS,2007.

[12] Orta, David R., et al, "A novel foamer for deliquification of condensate loaded wells", SPE-107980-MS, 2007.

[13] Willis, et al, "chemical foamers for gas well deliquification", SPE-115633-MS, 2008.

[14] Tang, et al, "plunger lift dynamic characteristics in a single well and network system for tight gas well deliquification", SPE-124571-MS, 2009.

[15] Pakulski, et al, "testing gas well deliquification chemicals at real downhole condition", SPE-121564-MS, 2009.

[16] Tang, et al,"A new method of plunger lift dynamic analysis and optimal design for gas well deliquification", SPE-116764-MS, 2009.

[17] Wang, John, et al, "Novel completion for effective deliquification of natural gas wells", SPE-120663-MS, 2009.

[18] Desheng, et al, "a new model for predicting gas-well liquid loading", SPE-120580-PA, 2010.

[19] Osman, et al, "gas well deliquification using microwave heating", SPE-134344-MS, 2010.

[20] Hearn, William James, et al, "Gas application overview well delifquification", SPE-138672-MS, 2010.

[21] Morrison, et al, "Experimental investigation of wellhead twin screw pump for gas well deliquification", SPE-159910-MS, 2012.

[22] Fenfen Huang, et al, "Optimized foamers for natural gas well deliquification: A statistical design approach", Nalco Company, Energy Services Division, 7705 Highway 90-A, Sugar Land, TX 77478, United States 2012.

[23] Van Nimwegwn, et al, "A first look at the hydrodynamics of air-water-foam flow for gas well deliquification", A025 BHR Conference Paper, 2012.

[24] Yousuf, et al, "Using dynamic simulation to assess the effectiveness of downhole pump for gas well deliquification", SPE-166093-MS, 2013.